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The role of hydrogen as long-duration energy storage and as an international energy carrier for electricity sector decarbonization

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Abstract

With countries and economies around the globe increasingly relying on non-dispatchable variable renewable energy (VRE), the need for effective energy storage and international carriers of low-carbon energy has intensified. This study delves into hydrogen's prospective, multifaceted contribution to decarbonizing the electricity sector, with emphasis on its utilization as a scalable technology for long-duration energy storage and as an international energy carrier. Using Japan as a case study, based on its ambitious national hydrogen strategy and plans to import liquefied hydrogen as a low-carbon fuel source, we employ advanced models encompassing capacity expansion and hourly dispatch. We explore diverse policy scenarios to unravel the timing, quantity, and operational intricacies of hydrogen deployment within a power system. Our findings highlight the essential role of hydrogen in providing a reliable power supply by balancing mismatches in VRE generation and load over several weeks and months and reducing the costs of achieving a zero-emission power system. The study recommends prioritizing domestically produced hydrogen, leveraging renewables for cost reduction, and strategically employing imported hydrogen as a risk hedge against potential spikes in battery storage and renewable energy costs. Furthermore, the strategic incorporation of hydrogen mitigates system costs and enhances energy self-sufficiency, informing policy design and investment strategies aligned with the dynamic global energy landscape.

1. Introduction

The global pursuit of decarbonizing electricity has typically emphasized solar photovoltaic (PV) and wind power technologies owing to their plummeting costs and abundant potential in many areas. However, as the share of non-dispatchable variable renewable energy (VRE) increases, long periods of imbalance between electricity demand and VRE generation, lasting weeks, months, or even seasons, pose significant challenges to grid reliability [1]. Moreover, achieving high VRE penetration may be difficult in some countries due to insufficient renewable or land resources or challenges associated with building and linking the necessary grid infrastructure. Hence, technologies that facilitate global decarbonization efforts address two key challenges: (1) long periods of electricity supply/demand imbalance in VRE-rich areas; and (2) generating decarbonized power in areas lacking suitable zero-carbon energy resources.

Hydrogen can address both challenges and is therefore a promising solution for power sector decarbonization [2]. First, hydrogen offers the potential for large-scale long-duration energy storage (LDES) by converting electricity into hydrogen using water electrolysis; the stored hydrogen gas can be later reconverted to electricity using a power-to-gas-to-power (PGP) fuel cell. Thus, as LDES, hydrogen can smooth long periods of energy imbalance on a VRE-based grid [3]. Second, hydrogen from electrolysis using zero-carbon electricity can be used as an international carrier of decarbonized energy [4, 5], enabling widespread decarbonized power generation in countries where zero-carbon energy sources are limited [6, 7]. These applications, while complementary, are also competitors in that their deployment hinges on their relative economics and the development of electricity markets to encourage their use.

There is no established definition of LDES, but following Shan *et al* [3], this paper defines LDES technologies as 'technologies that at minimum can provide inter-day applications.' However, geographical constraints can limit the deployment of pumped hydro storage and compressed air energy storage, two well-known LDES technologies [3]. In contrast, PGP is not bound by similar restrictions and can be expanded at scale to address long-duration energy imbalances. Consequently, large-scale hydrogen PGP projects are rapidly expanding globally [8–10].

Liquefied hydrogen is emerging as a critical international carrier of low-carbon energy, particularly in countries with limited renewable resources or where expanding grid and pipeline infrastructure is difficult [5]. Many nations, including Japan, South Korea, and Germany, plan to import liquefied hydrogen and hydrogen-derived fuels from renewable-rich regions for decarbonized power generation [11, 12]. Unlike technologies such as carbon capture and storage [13], liquefied hydrogen is not constrained by geographical limits. However, its import involves long lead times and significant investments in liquefaction infrastructure, vessel development, and the establishment of international supply chains built on long-term contracts [14]. Moreover, these investments, in both their timing and quantity, hinge on accurate information about liquid hydrogen's characteristics, particularly its operational pattern which, in turn, directly influences its revenue stream.

Informing hydrogen-related power sector investment planning and policy design requires a comprehensive examination of the competing roles of hydrogen as LDES and as an international energy carrier. However, there is a limited understanding of the role and needs of the international liquefied hydrogen trade in decarbonizing the electric power sector compared to domestic hydrogen production and use [13, 15, 16].

Most research on hydrogen use in the electric power sector has primarily focused on the United States (US) [13, 17, 18] and Europe [19, 20], where high-voltage transmission lines and existing gas pipelines (and not liquefied hydrogen) are employed for the international transport of renewable energy. Among the bulk power transmission methods at sea, liquid hydrogen becomes cost-competitive above 1000 km [9], making it appealing to Japan and other Asian countries. A growing body of literature has analyzed the techno-economic feasibility of transporting renewable energy to Asia via liquefied hydrogen from Australia [21], Chile [22, 23], and Canada [24]. However, these studies focus on the supply side (i.e. 'green hydrogen' production) and lack insight into hydrogen usage patterns and demand in importing countries. A few studies have explored the role of domestic and imported hydrogen in Japan's electric power system using a sector-coupling model [25], an economic power dispatch model [26, 27], and electric system simulations with several grid configurations and hydrogen demand scenarios [28]. However, these studies are inadequately detailed: some only model a snapshot of 2050, while others lack realistic sensitivity to renewable energy costs and electricity demand forecasts or detailed representations of power systems.

This significant gap in the literature leads to a lack of consensus within the academic and policy communities on the quantity of imported hydrogen necessary for power sector decarbonization. Under least-cost scenarios for a zero-emission grid in Japan, Matsuo *et al* argued that imported hydrogen would provide approximately half of power generation under a medium scenario [26, 27]; however, Burandt argued that a negligible amount of demand for imported hydrogen exists for power generation [25]. Determining pathways for hydrogen use in importing countries requires a comprehensive understanding of domestic and imported hydrogen production and use, as well as plausible parameters for hydrogen and renewable energy costs and technologies; these are absent from current literature.

To address these gaps, this study explores the conditions, extent, and manner in which hydrogen will be used in countries that will rely on its import for power sector decarbonization. Japan serves as a case study for several reasons. It established a pioneering national hydrogen strategy in 2017 [29] and updated it in 2023 [30]. It has also set specific near- and long-term power generation targets for imported hydrogen and ammonia [31]. Finally, Japan is committed to establishing an international liquefied hydrogen supply chain with other countries exemplified by initiatives like the Asia Zero Emissions Community [32]. Therefore, the timing and extent of Japan's prospective hydrogen imports hold critical implications for the energy landscape of the entire Asia-Pacific region.

This study aims to provide valuable insights into Japan's hydrogen-related policy design, investment planning, and decision-making by addressing the following key questions. First, what are the least-cost investment pathways to enable Japan's zero-emission electricity system by 2050? Second, what is the role of hydrogen in decarbonizing Japan's electricity sector, both as LDES and as an imported source of decarbonized firm power generation? Third, for each application, when and in what quantity must it be installed?

Fourth, what will the operational profile of hydrogen be for each application? Finally, how will critical policy decisions and responses to uncertainty affect the timing and amount of hydrogen deployment, as well as system costs and operations, in Japan's decarbonized electricity sector?

By comprehensively examining the use of hydrogen in Japan, this study can serve as a useful reference for other countries, particularly those facing similar energy transition challenges and anticipating the dual use of hydrogen in the power sector.

2. Methods

2.1. Modeling approach

This study employs a robust modeling framework that integrates capacity expansion and hourly dispatch models within the platform known as solar and wind energy integrated with transmission and conventional sources (SWITCH). Developed as an open-source tool [33], SWITCH facilitates assessments of the profound impacts of high renewable energy penetration on electric power systems. Since its launch, SWITCH has evolved through diverse country-specific applications to the US, China, among others (e.g. [34–38]).

The SWITCH model employs linear programming to determine the least-cost investment in and operation of generation, storage, and transmission capacities. Moreover, it accommodates policy decisions and adheres to reliability, operational, and resource constraints. Because SWITCH does not allow energy stored in one day to be carried over to another, this study created a modified 'SWITCH-Japan' model to allow such carry-over and thus enable analysis of LDES. Furthermore, the two-stage modeling approach we developed enables the characterization of hydrogen energy storage investments and operations on a high-VRE grid over the lifetime of those investments. The detailed method is outlined in supporting information S1.

Initially, we employ a capacity expansion model to pinpoint the least-cost configuration of generation, storage, and inter-regional transmission investments and operations from 2025 to 2050 that satisfies regional electricity demands, grid reliability requirements, and carbon emissions targets to achieve a zero carbon grid by 2050. We define a zero-carbon grid in this study as a grid where all generation sources do not produce direct CO_2 emissions. The capacity expansion model conducts 365 day simulations for 2025, 2030, 2035, 2040, 2045, and 2050, and accurately captures the LDES characteristics that address seasonal variations in load and VRE generation. In the first stage, dispatch simulations are averaged every 4 h, aligning with diurnal variations in electricity demand and VRE output as previously established [34–36] to facilitate the computational tractability of characterizing a large range of load and weather conditions. Subsequently, a production cost model is employed to detail the least-cost unit-commitment and economic dispatch operation of generators for all 8760 h of the year, along with storage and transmission resources identified in the least-cost portfolio.

2.2. Data utilization

This study uses exogenously determined costs, lifetimes, and technological parameters extracted from the latest literature (SI S2.2–S2.5). We combine local and global data to obtain projections incorporating the rapid cost-reduction trends observed in solar PV, wind, battery storage, hydrogen production, and transportation costs. The National Renewable Energy Laboratory's Annual Technology Baseline provides extensive long-term cost forecasts until 2050 [39]. Data adjustments for this study are made considering the historical cost deviations between the US and Japan [40]. Additionally, Japan-specific hydrogen production and transportation cost estimates have been sourced from the literature [21, 22].

2.3. Scenario analysis and sensitivity assessment

This study employs a comprehensive approach to exploring the impact of imported and domestic hydrogen on wholesale electricity costs and Japan's generation mix across four scenarios: Base, No Hydrogen, Domestic Hydrogen, and Imported Hydrogen.

The Base scenario simulates the least-cost capacity expansion of the electricity system from 2025 to 2050, and encompasses both imported hydrogen and hydrogen storage deployment. Subsequently, an hourly dispatch analysis examines the energy storage operations and overall system reliability. The model assumptions are given in table 1.

The No Hydrogen scenario excludes imported hydrogen and hydrogen storage deployment, thereby providing a benchmark for assessing the impact of hydrogen on the electricity system. The Domestic Hydrogen scenario and the Imported Hydrogen scenario exclude either imported hydrogen or hydrogen energy storage, respectively, offering insight into the implications of relying solely on domestic or imported hydrogen.

This study calculates the changes in the generation, storage, and transmission capacity mix, along with total system costs, based on the least-cost pathways for each scenario. System costs are defined as the cost of generation and storage, plus incremental transmission investments (SI S1.4(1)). To enhance robustness, we have also conducted sensitivity analyses for critical factors, including imported hydrogen prices, hydrogen storage costs, domestic renewable energy costs, and battery costs for the Base Scenario.

Table 1. Summary of key assumptions.

Parameters	Assumptions	Sources
Geographic scope	10 regions (nodes)	Reflect Japan's ten regional monopoly-run transmission and distribution services
Cost parameters	Japan-specific data, NREL ATB 2022 with adjustments (see SI S2.3).	Japan's 6th Strategic Energy Plan [31], NREL ATB 2022 [39], expert consultation
Electricity demand	50% increase by 2050 from 2020 levels	Japan's 6th Strategic Energy Plan [31]
Weighted Average Cost of Capital (WACC)	3% (real)	Expert consultation
Renewable energy potential	Available areas are based on Government of Japan (GoJ) data. Hourly simulation data is from Renewable Ninja (see SI S2.3.4).	Japan's Ministry of the Environment [41], Renewable Ninja [42–45]

Table 2. Summary of scenario analysis and sensitivity assessment.

Types	Name	Difference from the base scenario
Scenario analysis	No Hydrogen Scenario	Neither domestic hydrogen (i.e. hydrogen storage) or imported hydrogen is allowed.
	Domestic hydrogen scenario	Only domestic hydrogen is allowed.
	Imported hydrogen scenario	Only imported hydrogen is allowed.
Sensitivity assessment	High/low imported H2 cost case	Imported hydrogen cost projection from 2025 to 2050 (see SI S2.5 and table S5)
	High/low hydrogen storage cost case	Hydrogen storage cost projection from 2025 to 2050 (see SI S2.3.2 and table S3)
	High/low renewable cost case	Renewable storage cost projection from 2025 to 2050 (see SI S2.3.2 and figure S4)
	High/low battery cost case	Battery storage cost projection from 2025 to 2050 (see table S2.3.2 and SI S3)

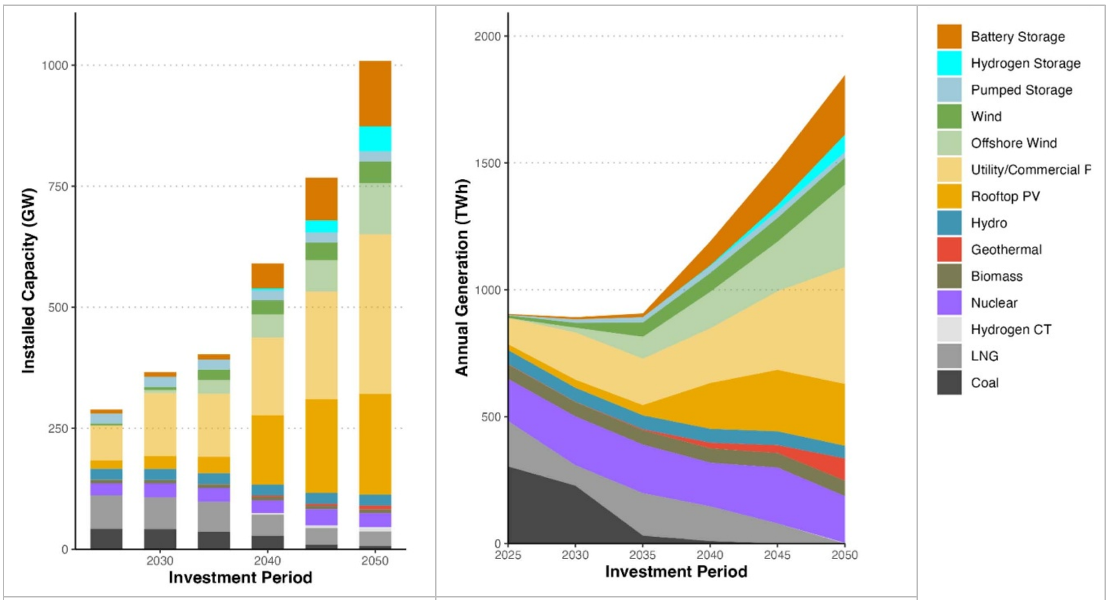
The overview of scenario analysis and sensitivity assessment are summarized in table 2. Detailed model descriptions, descriptive statistics, and additional results are provided in the supporting information.

3. Results

3.1. Investment landscape under the base scenario

Our findings underscore the feasibility of achieving a zero-emission power system in Japan through substantial investments in renewables, hydrogen, battery storage, and transmission infrastructure. Together, solar and wind power constitute three-quarters (74.7%) of the least-cost electricity mix, necessitating a robust combination of clean, firm generation and various storage options to address their inherent variability across different timescales.

In the Base scenario, hydrogen is pivotal for balancing long-duration mismatches between electricity demand and VRE generation. The vast majority (97%) of hydrogen is produced domestically in Japan using clean electricity, stored, and used for electricity generation (i.e. hydrogen storage) in 2050. The remaining 3% is sourced through imports. Figures 1(a) and (b) present the installed capacity and generation mix, respectively, in the Base scenario through 2050. Generation and storage capacity more than triples over that time, from 288 GW in



(a) Capacity mix (GW)

(b) Generation mix (TWh/year)

Figure 1. Evolution of Japan's electric power system from 2025 to 2050 under the Base scenario.

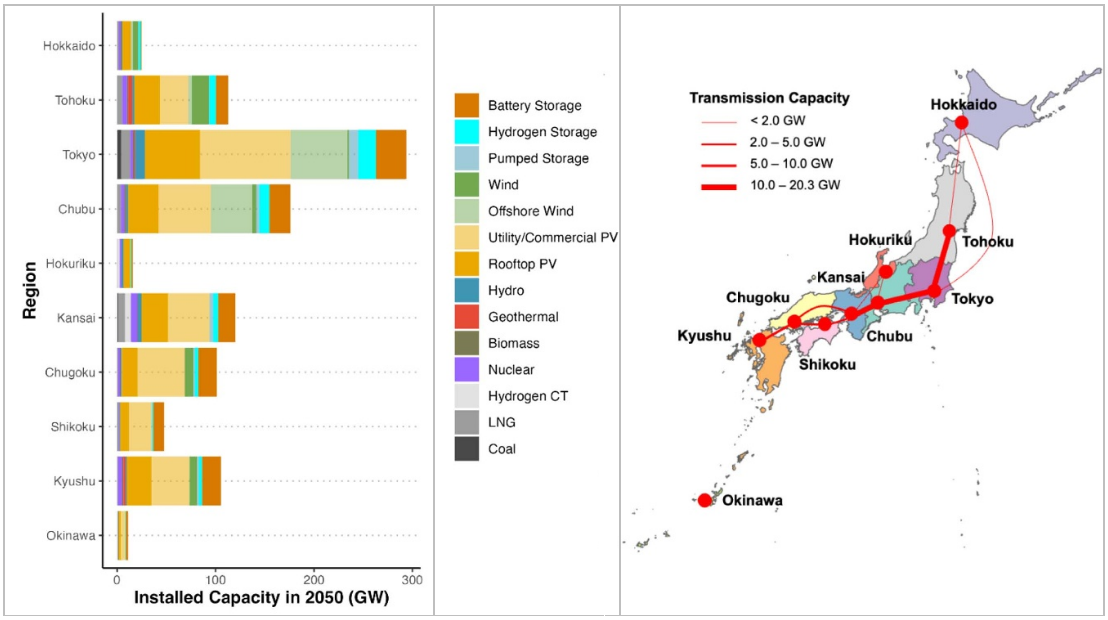


Figure 2. Regional details of generation, storage, and transmission capacities in 2050 under the Base scenario.

2025 to 1009 GW in 2050. The least-cost electricity mix for 2050 comprises utility-scale and commercial solar (30.3%), offshore wind (21.4%), rooftop solar (16.0%), nuclear (12.1%), onshore wind (6.9%), geothermal (5.8%), biomass (4.0%), hydropower (3.3%), and imported hydrogen (0.2%). Figure 2 summarizes the regional details of generation, storage, and transmission capacities in 2050 un the Base Scenario.

As carbon constraints intensify (see table S1), a pronounced shift from coal- and natural gas-fired power generation to hydrogen storage and hydrogen-fired power generation is observed from 2045. To achieve a zero-carbon grid with peak and average loads of 237 and 155 GW, respectively, Japan requires 51 GW (29.8 TWh) of hydrogen storage, 135 GW (900 GWh) of battery storage, and 9.1 GW of hydrogen-fired power plants by 2050. Hydrogen storage boasts an average energy storage duration of 580 h, compared to just 6.7 h for battery storage, reflecting the low energy capacity costs for hydrogen

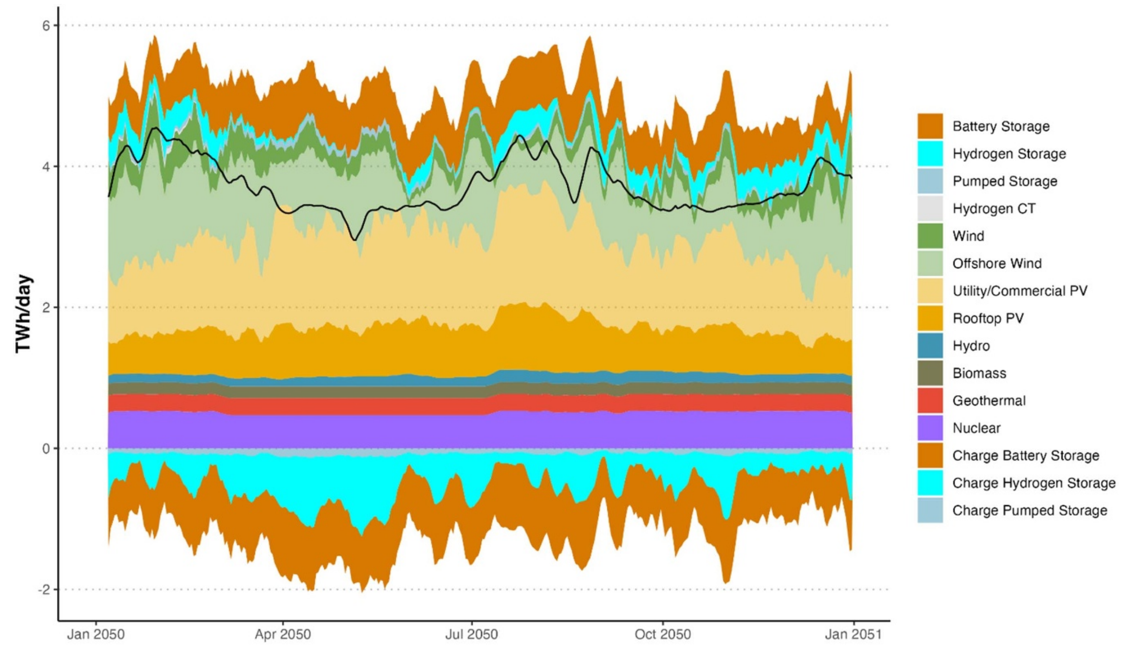


Figure 3. Annual national dispatch results with seven-day averaging under the Base scenario. The black solid line represents Japan's national load.

storage. Substantial additions to interregional transmission lines, which expand from 21 GW in 2025 to 47 GW in 2050, can smooth renewable output variations across wider geographic areas.

Average system costs in 2050 (96 USD/MWh) is 4% lower than the 2025 levels (100 USD/MWh). The energy self-sufficiency rate—the ratio of total electricity demand met by domestic sources [46]—increases from 28% in 2025 to 88% in 2050 with imported nuclear fuel and imported hydrogen accounting for the remaining 12%, helping insulate Japan's economy from the impact of fluctuating fossil fuel import prices.

By demonstrating how renewables, hydrogen, battery storage, and enhanced transmission capabilities can produce a reliable, cost-effective, and zero-emission power system, the Base scenario offers a blueprint for transforming Japan's energy system to achieve a sustainable energy future.

3.2. Hourly dispatch dynamics in the base scenario

We conducted hourly simulations of the least-cost operation of Japan's electricity grid under the Base scenario in 2050. The resulting system dispatch (figure 3) illustrates the temporal patterns of generation, storage, and load. The net load (i.e. load minus VRE output) exhibited multiday, weekly, monthly, and seasonal variations (figure 4). The daily net load frequently fluctuates, with a mean and standard deviation of 0.616 and 0.707 TWh d^{-1}, respectively. Hydrogen storage is critical for addressing these fluctuations. The daily net load is at its lowest in spring and peaks in summer and winter, while there are also significant fluctuations that span weeks or months as shown in figure 4. Approximately 10% of available renewable energy must be curtailed annually.

Figure 5 illustrates the distinctive characteristics of hydrogen storage compared to other energy storage technologies in 2050 under the Base scenario. Battery and pumped storage resources cycle more frequently than hydrogen storage. Using the rainflow counting method, battery and pumped hydro storage recorded 362.0 and 327.0 cycles per year, respectively, charging and discharging daily to balance intra-day (i.e. same-day) mismatches between VRE generation and load.

Hydrogen storage, in contrast, cycles only 11.5 times per year and stores up to the equivalent of 178 h of the average national electricity demand (figure 5). This extended discharge capability underlines hydrogen's pivotal role as a long-duration balancing resource to manage longer-term fluctuations in net electricity demand. Similarly, hydrogen-fired power plants operate exclusively during periods of high net load, as shown in figure 3.

3.3. Sensitivity assessment

We perform sensitivity assessments to explore variations in cost inputs for imported hydrogen, renewable energy technologies, battery technology, and hydrogen storage technology. Results from the Base scenario are consistent across all sensitivity cases, demonstrating the robustness of our findings. Figure 6 outlines the differences in system costs,

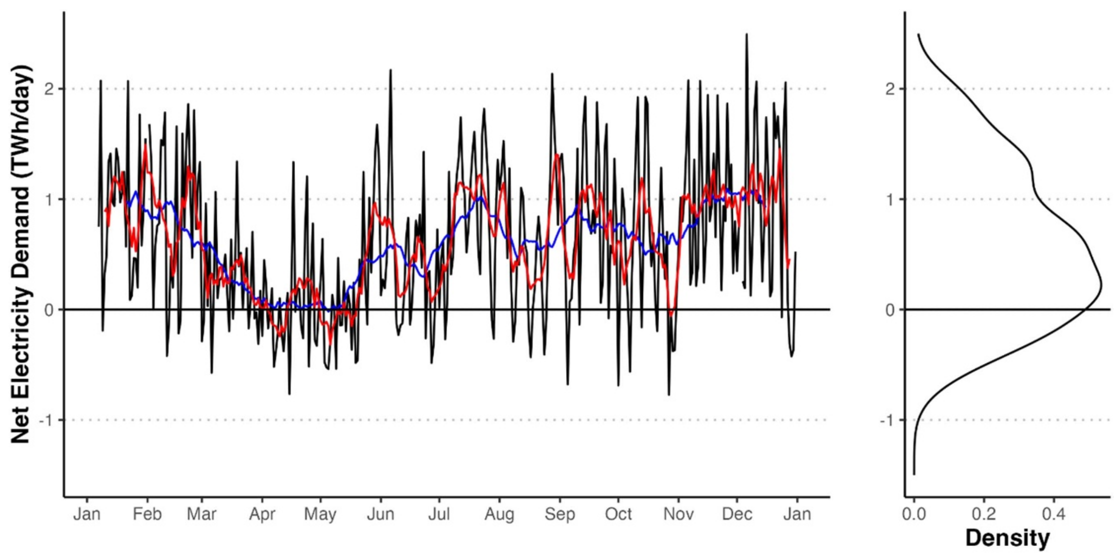


Figure 4. Net electricity demand per day in 2050 under the Base scenario (left) and its frequency distribution (right). The red and blue lines in the left figure represent 7 d and 30 d moving averages, respectively.

installed capacity, and electricity generation from domestic and imported hydrogen across the sensitivity cases.

The sensitivity assessments indicates that the average system costs in 2050 remain similar regardless of cost input variations, ranging from −6.2% (Low RE Cost Case) to +9.0% (High RE Cost Case). These relatively stable system costs highlight the adaptability of the least-cost system, which adjusts the generation, storage, and transmission portfolio in response to changing cost inputs (figure 6(b)). While the demand for domestic and imported hydrogen depends on factors such as the price of imported hydrogen and technology costs, overwhelming majority of hydrogen is domestically produced and used to generate electricity in all cases (figure 6(c)).

3.4. Scenario analysis on hydrogen availability

We further assessed the impact of hydrogen availability on achieving a zero-carbon grid. Figure 6(b) illustrates that the absence of hydrogen storage significantly increases the difficulty of achieving zero-emission electric power systems, requiring substantial additions to VRE, battery storage, and transmission capacities and thereby increasing costs.

In the No Hydrogen scenario, the system requires 25 GW more VRE capacity and 15 GW more interregional transmission. In addition, battery storage requirements significantly increase by 37 GW (1.66 TWh). Relying on the timely construction of solar, wind, and transmission capacities at such a large scale poses a substantial risk compared to the Base scenario. Moreover, the average electricity cost under the No Hydrogen scenario is 20% higher than under the Base scenario in 2050.

In the Imported Hydrogen scenario, multiday and seasonal mismatches are addressed by 40 GW of hydrogen-fired power plants with substantial addition of battery (36 GW; 406 GWh) and transmission (16 GW) capacity. Moreover, system costs increase by 9.3% in 2050. Imported hydrogen ultimately accounts for 46.3 TWh yr^{-1} of electricity generation, or 3.3% of the generation mix in 2050.

The Domestic Hydrogen scenario demonstrates that domestically produced hydrogen can effectively replace imported hydrogen with only a marginal increase (1.5%) in the system cost in 2050.

4. Discussion

This study explores various scenarios and input assumptions for achieving a zero-carbon electric power system in Japan by 2050 and underscores the feasibility of this pursuit. While the pathways to this objective may vary, the common thread is the need for substantial investments in solar- and wind-based electricity grids complemented by hydrogen storage, battery storage, clean firm power, and transmission infrastructure as shown in table 3.

Hydrogen is essential to providing a reliable power supply by balancing extended mismatches between VRE generation and load over weeks or longer. The findings affirm hydrogen's significant contribution to reducing the risks and costs of achieving zero-emission power systems. Moreover, the results suggest prioritizing domestically produced hydrogen, leveraging renewables for cost reduction, and strategically employing imported hydrogen as a risk hedge against potential spikes in battery storage and renewable energy costs.

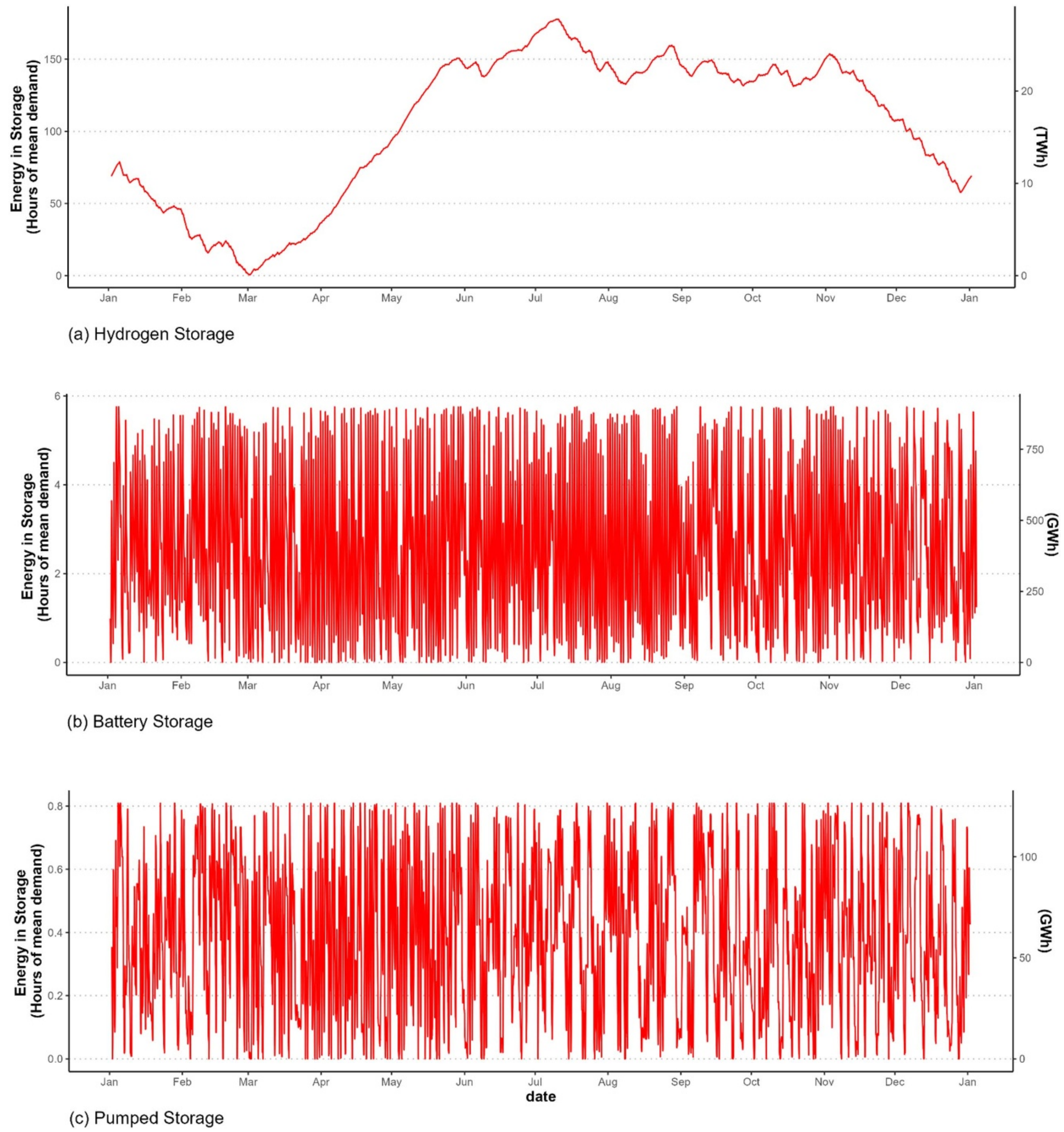


Figure 5. Cycling of energy storage resources in 2050 under the Base scenario.

A long-term commitment to hydrogen necessitates accurate demand estimates for domestic and imported hydrogen for GoJ to facilitate hydrogen investments. Japan plans to consume 12 million tons (400 TWh) of hydrogen per year by 2040 and 20 million tons (667 TWh) by 2050 [30]. This study estimates demand for hydrogen in the power sector to reach 64–92 TWh by 2050, with the overwhelming majority of it being domestically produced.

Regarding imported hydrogen, several factors underscore the need for caution in long-term planning. These include concerns about the risks of price volatility, akin to the fluctuations observed in natural gas prices in 2022 and many other years; avoiding investments in excessive production capacity; and the difficulty of establishing long-term contracts in international supply chains [47, 48]. Notably, even with no hydrogen storage at all, imported hydrogen comprises at most 46 TWh, affirming the importance of not overestimating demand for imported hydrogen. Conversely, the risks associated with domestically produced hydrogen relate to the costs of domestic renewables and electrolyzers, which could increase domestic hydrogen production costs as shown in figure 6(c).

This study focuses on the role of hydrogen as a power-to-power storage and renewable-specific technology pathway and provides a foundation for subsequent investigations that can delve into the broader portfolio of zero- or negative-emission technologies, including direct air capture. The potential of hydrogen as a cross-sector energy storage resource across electricity, industry, transportation, and other hard-to-abate sectors [2, 6] introduces complexities not yet accounted for in the current SWITCH-Japan version. Considerations of sector coupling and demand-side

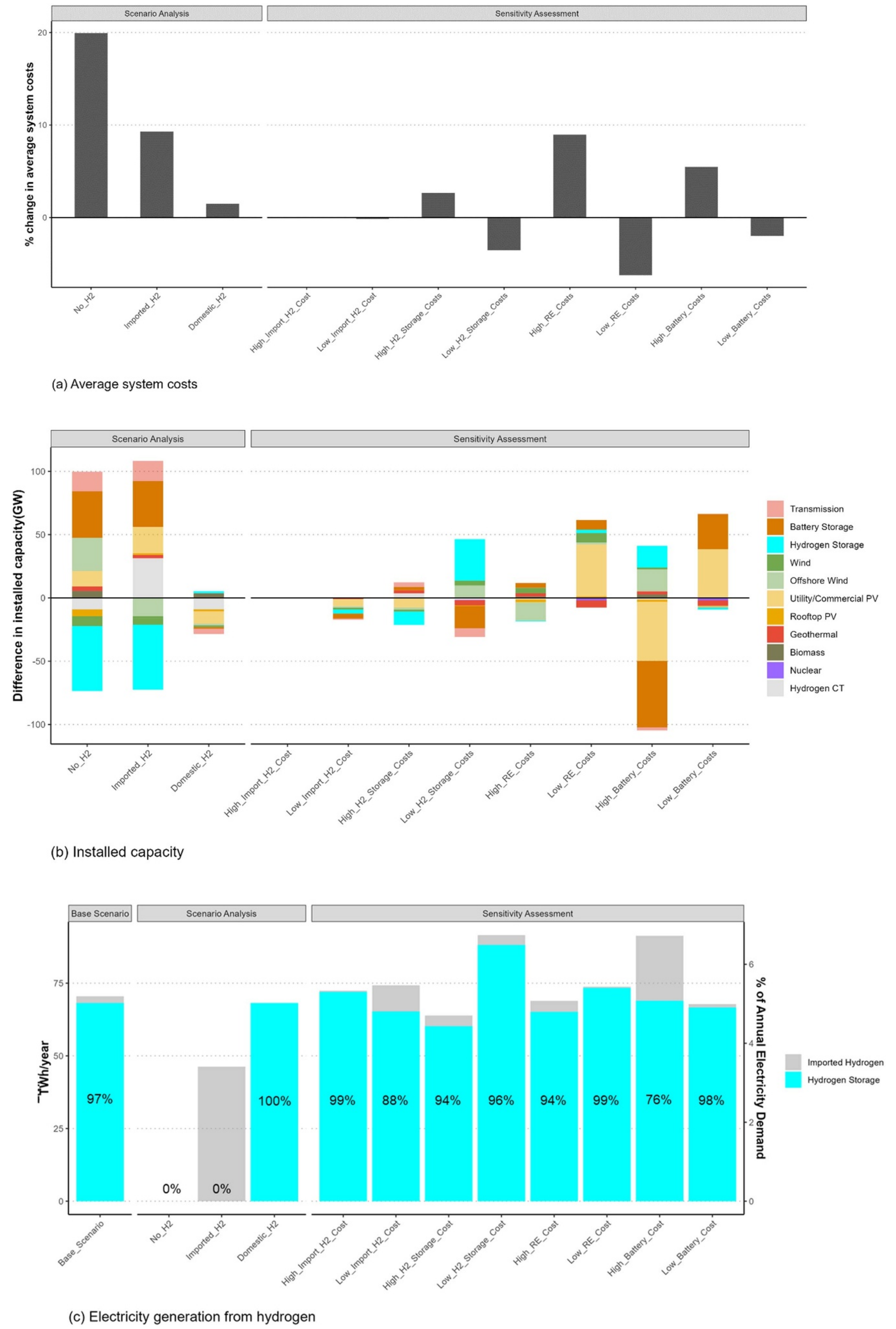


Figure 6. Scenario analysis and sensitivity assessment results in 2050: (a) average system costs; (b) installed capacity; (c) electricity generation from hydrogen.

Table 3. Reference carbon-neutral electricity mix in 2050.

Energy source	FY2019 [27]	FY2030 target in 6th strategic energy plan [34]	FY2050 base scenario (sensitivity range)
Variable renewables (solar and wind)	8% 60 GW	19%–21% 127–141 GW	75% (73%–79%) 688 GW (658–738 GW)
Firm renewables (hydro, geothermal, and biomass)	10% 30 GW	17% 33 GW	13% (8%–14%) 39 GW (33–44 GW)
Nuclear	3% 10 GW	20%–22% ∼25 GW	12% (12%–13%) 29 GW (27–29 GW)
Hydrogen (import)	0% 0 GW	1% —	0.2% (0.03%–1.5%) 9.1 GW (7.6–12.6 GW)
Fossil fuels	79% 120 GW	41% —	0% 37 GW
Energy storage (pumped hydro, battery, hydrogen)	21 GW 126 GWh	—	208 GW (172–234 GW) 31 TWh (27–36 TWh)

impacts on the electric power sector, in conjunction with industry and transportation sector impacts, are anticipated for the next phase of model development; these will enrich our holistic understanding of the transition toward a sustainable, decarbonized future. Furthermore, future research could build on our findings to spatially optimize hydrogen production, storage/reserve, and bulk transportation to economically decarbonize the entire energy system and enhance its energy security. Additionally, future research will delve into the impact of year-to-year variability in solar and wind output on the role of hydrogen storage as a strategic energy reserve, paralleling the role played by conventional systems in the current energy landscape [2].

5. Conclusion

This study advances our understanding of the transformative journey toward Japan's 2050 carbon neutrality target by delineating key policy and technological choices that are pivotal to the energy transition of the nation's electric power system. The consistent demonstration of the economic feasibility of achieving a zero-carbon grid by 2050, relying on a combination of domestic and imported hydrogen, positions Japan as a global leader in an energy transition facilitated by hydrogen. Japan's energy transition is a critical case study for other countries navigating their unique pathways toward a sustainable and decarbonized future. The strategic integration of hydrogen into the energy landscape will become a beacon for global discussions and enshrine hydrogen's pivotal role in unlocking a sustainable, resilient, and carbon-neutral energy paradigm. Further studies are required to comprehensively understand the nuances of hydrogen's role in decarbonizing entire economies beyond the electric power sector.

Data availability statement

All data that support the findings of this study are included within the article (and any supplementary files).

Conflict of interest

The authors have declared that no competing interests exist.

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